STATE OF VERMONT
PUBLIC SERVICE BOARD

Docket No. 6120

Tariff filing of Central Vermont Public Service)
Corporation requesting a 12.9% rate increase, to)
take effect July 27, 1998)

Docket No. 6460

Tariff filing of Central Vermont Public Service)
Corporation requesting a 7.6% rate increase, to)
take effect December 24, 2000)

PREFILED TESTIMONY OF
DAVID F. LAMONT
ON BEHALF OF THE
VERMONT DEPARTMENT OF PUBLIC SERVICE

March 9, 2001

Summary: The purpose of Mr. Lamont's testimony is to address certain issues with CV's proposed power cost estimates.

Prefiled Testimony
of
David F. Lamont

Q. Please state your name and occupation.

A. My name is David F. Lamont, and I am a Power Supply Planner for the Vermont Department of Public Service (Department or DPS). My business address is 112 State Street, Montpelier, Vermont.

Q. Please summarize your professional background and experience.

A. I have worked for the Department since 1986 in various capacities, both as a DSM analyst and in my present position as a Power Supply Planner. Prior to that, I worked for the Vermont State Energy Office where I was involved in the numerous energy efficiency programs and in reviewing the energy efficiency of new construction under Act 250.

Q. Have you ever testified before the Vermont Public Service Board before?

A. I have testified in Docket Nos. 5270, 5329, 5370, 5428, 5483, 5491, 5533, 5630/5632, 5656, 5695, 5810/5811/5812, 5823, 5828, 5857, 5859, 5863, 5983, 6043, 6107 and others as well as before the District Environmental Commissions and the Environmental Board in numerous Act 250 cases.

Q. What is the purpose of your testimony?

A. My testimony proposes several adjustments to CV’s projected rate year power costs. In addition, I propose the deferral and amortization of some costs as well as the creation of a regulatory liability to be used to offset deferred DSM expenses.

Q. Please discuss your adjustments

A. I am proposing 8 adjustments totaling $4.03 million They include the following adjustments with the corresponding values:

1. Market Price	$2,000
2. ICAP Price (@$1.65)	$ 900
3. FACTS Deferral	$ 400
4. VJO Energy Price	$ 130
5. VPX Projections	$ 100
6. Phase II value	$ 100
7. Hydro Production	$ 400
Total	$ 4,030

Additionally, I propose the creation of a regulatory asset for an approximately $1,000,000 refund payment made from Citizens Utilities to CVPS.

Q. Please discuss CV's new power cost model.

A. CV uses an elaborate and thoughtful spreadsheet based model to project power costs in the rate year. Non-dispatchable and base load unit production is allocated over peak and off peak hours as appropriate. Dispatch of intermediate and peaking units is driven off of an hourly market price. If the market price is high enough, it is modeled as dispatched in that hour. This is a somewhat simplified description of the model logic, however, the important aspect is the influence of the market price on unit dispatch. CV's load is then compared to the total dispatch of the units. Any generation in excess of CV's load requirements is assumed sold at the market price and, conversely, any shortfall is purchased at the forecasted market clearing price in that hour.

Q. Please discuss your market price adjustment

A. As a result of this simulation, CV expects to be a net seller into the ISO New England market during the rate year. (CV's market activity has declined significantly from the test year due to the expiration of its relationship with Virginia Power. This can be most readily seen in Exhibit CV Watts/Howland-4 where both Net System Purchases and Net credits show large decreases) As a result, increases in the projected market price of energy generate increased revenue for CVPS.

In its model, CV used an annual average market clearing price estimate of $41.86/MWh. My adjustment was based on an annual average forward market price of $51.95/MWh.

Q. How did you derive your estimate of market prices in the rate year?

A. My price was developed from available forward price data published by Natsource and reflects posted forward prices on February 26, 2001. This sheet is attached as Exhibit DPS-DFL-1. To determine an average monthly price, I used a simple average of four prices - the peak and off peak, bid and ask prices. These are prices at which futures buyers will buy and futures sellers would have sold power on that day. For example, to develop a market price for July and August of 2001, I averaged the peak and off peak bid prices of $100.50 and 50.00 (prices at which a buyer would have purchased) and the peak and off peak ask prices of $101.75 and 51.50 (prices at which a seller would have sold) to get a market price of $75.94 for July and August. For months where there was incomplete data, I estimated prices based on similar months for which there was data. To create hourly market prices from these monthly averages, I used the same method CV used to adjust the historical market prices in it's power cost model, substituting my forecast price for theirs. This higher market price produced a net wholesale revenue increase of $2.9 million dollars.

Q. You are only proposing an adjustment of 2.0 million dollars. Why are you not proposing the entire $2.9 million adjustment?

A. There are reasons why CV might not want to sell its entire surplus in the forward market. It is conceivable that the posted prices may represent a "thin" market. An addition of 25 or 50 MW on the supply side of the market could cause the price to fall somewhat. Also, in order to sell its surplus energy, they couldn't just sell their excess in any hour, but CV would have to sell a "strip" of energy. This would be a fixed amount of energy over an entire month (7x24), over the peak hours in a month (5x16) or the off peak hours in any month (5x8, 2x24) as shown on the Natsource sheet. This fixed sale would mean that in hours when CV was already purchasing from the spot market, they would have to increase that purchase, in hours when they were surplus less than their sale amount, they would go from a seller to a buyer in the spot market, and in those hours where they were surplus more than the sale amount, they would retain some energy to sell on the spot market. This shortfall would expose CV to additional risk in the event of unanticipated market price spikes or unexpected unit outages.

Conversely, this could be a windfall if CV should have excess energy in those hours where a spike occurs. While CV is exposed to the risk of extended outages, it is somewhat compensated by the use of four year average forced outage rates in rate making. Should a unit be unexpectedly out of service for any length of time, CV does not have to remain at the mercy of spot prices, but can make a purchase to cover its shortfall. Also, CV may incur a cost to funnel such a transaction through a broker.

On the other hand, the 2.9 million, in some sense, represents the premium on an insurance policy, paid for by the ratepayers, which benefits CVPS. Some level of insurance against risk is appropriate - the question is how much. Further, CV's own actions appear to demonstrate that CV is unwilling to "purchase" this insurance from other sources available to it. I discuss this point further below. There is the potential for additional gain for the Company by selling its surplus in the forward market. Although the Natsource prices represent the forward price where buyers and sellers have settled for a given future time period, there is some reason to believe that there is a risk premium in those prices such that actual spot market clearing prices could likely be less than the forward prices. The $2.9 million adjustment assumes that any market energy required is purchased at this forward price instead of the spot price. If the spot price turns out to be lower than the futures price, benefits to CV in addition to the $2.9 million will result.

For these reasons, I chose to recommend an adjustment which starts at 2.9 million, but recognizes that some risk should be shared but also that such a strategy could result in additional benefits for CV. I chose $2.0 million as representative of this amount.

Q. Please explain your comment regarding CV's failure to purchase insurance against higher than expected market prices.

R. I see two signs of a reluctance to acquire additional energy supplies. The first is CV's unwillingness to increase the capacity (and energy output) of Vermont Yankee. This is discussed in DPS Witness Sherman's testimony. Clearly additional VY capacity would increase CV's energy security. This energy could be retained as "insurance" or sold into the futures market as described above. The second is an apparent change in CV's policy regarding investments in its owned units. Exhibit DPS-DFL-2, is a memo from Larry Wright to Alf Strom-Olsen in which he discusses a change in the way Systems Operation and Production will treat future work order requests. That change is to move work order requests from the non-discretionary category to the discretionary category. I have submitted discovery on this issue to get a further explanation, but at least on its face, this does not seem like the actions of a company concerned with the reliability of its generation portfolio.

Q. Please explain the ICAP adjustment.

A. CV is a net purchaser of ICAP. At the time the case was filed, forward ICAP prices were in the range of $1.65.kW-month. CV chose to pro form a price of $4.00 /kW-month. Since August, the ICAP market has been the subject of much controversy and uncertainty. I will not go into the details here, however it is just not reasonable to “charge” the ratepayers nearly 3 times the going rate for this product. Adjusting this price results in a revenue requirement change of roughly $900,000..

Q. How is it reasonable to assume current future prices for energy and historical future prices for ICAP?

A. Since CV filed its case, both energy and capacity prices have risen substantially. Energy prices largely due to fuel price increases and ICAP prices due to FERC rulings regarding the ICAP market in ISO-New England. As I stated above, at the time of its filing CV was prepared to charge the ratepayers $4.00 for something that was available for $1.65. Although current forward price are higher than that ($2.50), if CV truly believed at the time of their filing, that prices would be $4.00 in the rate year, they should have bought ICAP prior to filing.

CV could have also sold its surplus energy at the lower prices available at the time the case was filed. However at the prices available at that time, the potential revenue gains would have been minimal and likely would have not justified the additional risks discussed above. In the case of energy, the market has moved since the filing. Since CV retains the option to sell, it is reasonable to incorporate more recent information.

Q. What are you recommending for the deferral of the costs for the FACTS device?

The FACTS device is a transmission upgrade built by VELCO. Eventually, it will become part of the pool transmission facilities (PTF) and its costs will be paid out of the PTF payments made by load serving entities throughout New England. There is a period of about one year when VELCO (and hence the Vermont utilities) will be paying the entire carrying cost of this facility prior to its being included in the PTF facilities rate. The timing of this rate case is such that it includes many of those months. It is my feeling that these extraordinary costs should be put into a regulatory asset which will be collected commensurate with payments from PTF charges. Deferring and amortizing only a portion of these charges in the rate year results in a rate year savings of $600,000.

Q. Do you have any other power cost adjustments?

A. Yes, I am proposing two minor adjustments to the VJO price and CV's VEPPI allocation. The HQ VJO energy prices increases annually by an inflation index. Since the rate year covers two power years in terms of the VJO contract the annual rate should be a combination of these two forecasted prices. CV used only the 2002 price. This lowers costs by $125,000.

Power (and cost responsibilities) from VEPPI sources are allocated each year based on retail sales from the previous year. Each year, for the past 4 years, CV's allocation of VEPPI power has decreased. I see nothing to change this trend and am recommending that CV's share of VEPPI power be reduced by 3/4 of 1%. This results in a cost savings of roughly $100,000. Exhibit DPS-DFL-3 shows this trend.

Q. What about your proposed adjustment for CV's hydro production?

In its filing, CV made certain adjustments to its expected hydro production to reflect relicensing conditions expected to be in place during the rate year. Further, they made no adjustments to reflect increased generation anticipated as the result of capital improvements made to several of their stations and proposed for rate base treatment in this case. As a result, anticipated hydro generation was understated. Increasing this to more reasonable levels - although still below 20 year average levels - results in a decrese in expenses of roughly $400,000.

Q. Please explain your proposal for crediting the refund payments made by Citizens to CV as a result of transmission overcharges.

A. As a result of a settlement in a FERC docket, Citizens Utilities has agreed to refund certain overcharges in made for transmission service. Citizens has made a refund of approximately $1,000,000 to CV, but has contested the transmission audit on which the amount was based and is attempting to get the refund refunded. It is my understanding that the parties are in settlement discussions. Once CV has determined with certainty the amount of the refund, the Board should create a regulatory liability and CV should use this refund to offset deferred amount in its DSM accounts.

Q. Does that conclude your testimony?

A. Yes